Powering Arizona

Choices & Trade-Offs for Electricity Policy

A Study Assessing Arizona's Energy Future

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Preface

Energy is a critically important issue around the world with immense economic and environmental ramifications. The significant increase in oil prices in the spring of 2008 dramatically demonstrates the impact of energy costs to consumers as well as every sector of our economy. In Arizona, the supply of energy impacts every aspect of daily life for the more than six million people who live in the region. The debate on global climate change has also added a new dimension to providing for the nation's energy future, sometimes dwarfing the big questions of supply and demand and highlighting the need for sensible decisions by public and private institutions.

Political leaders from both parties are calling for the use of alternative energy technologies such as hydrogen, solar, and wind, but there is widespread confusion about their economic and technological viability. At the same time, oil and natural gas prices continue to fluctuate and there is on-going concern about the nation's energy dependence on countries in the volatile Middle East as well as Russia. It is clear that Arizona and the entire nation will need all of the energy it can obtain from <u>all</u> sources including fossil fuels, nuclear, and renewable sources.

It is also necessary to put energy issues in context with economic issues at the state and national levels. While much of the domestic discussion has been on the federal level, individual states like California are attempting to deal with energy and global climate change through state-based regulatory programs. An accurate understanding of the overall situation must include an evaluation of the cost and benefit of all energy sources, renewable and traditional, along with environmental and other regulations that impact energy policy and supply.

Facing Arizona's Energy Future

Every day more people are moving to Arizona, many because of the favorable business climate and the beautiful weather. A significant by-product of this growth is the increased demand for energy. Consider the following facts from the United States Energy Information Agency about energy and growth in Arizona:

- 23% increase in gasoline use in the past decade
- 28% use of diesel oil in the past decade
- 25% increase in the use of natural gas in the past five years
- 17.8 % growth in population from 2000 to 2005

Arizona has experienced tremendous growth in recent decades. Governor Janet Napolitano has asked a critical question: "How much energy is Arizona going to need if we add 1,000,000 new homes?" The Governor has also asked how the state can make better use of new renewable sources of energy and conservation to close that gap. This research project is dedicated to answering these and other vitally important questions.

This preliminary report will also consider the economic cost of various scenarios or energy mixes that must be considered by policy makers at all levels along with opinion leaders and the public. We believe this report provides a valuable input for other states in considering their energy future.

We are indebted to the Thomas R. Brown Foundations for their support of this research project. We were fortunate to have two renowned scholars, Dr. **Timothy Considine** Ph.D., Professor of Natural Resource Economics, Pennsylvania State University, and **Dawn McLaren**, Research Economist, W. P. Carey School of Business, Arizona State University. Dr. Considine has extensive experience in conducting these types of studies, having conducted energy studies for many organizations including the State of Israel and the World Bank. Ms. McLaren has also spent a great deal of time researching energy use in Arizona and other issues involving the basic economic and business climate of the state.

We hope that this study provides valuable information in the consideration of issues of incredible importance to the state and its millions of residents.

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Introduction

Like other Americans, residents of Arizona have been struggling under the weight of higher prices for gasoline, natural gas, and other energy services. The price of oil adjusted for inflation is currently at levels not seen since the dawn of the oil age more than 150 years ago. While there is great uncertainty surrounding the future course of oil prices, the odds for a return to the lower prices of the past are increasingly remote.

In the midst of these growing concerns about the cost of energy many governments are adopting policies, such as renewable fuel standards and carbon cap and trade regulatory systems, to limit emissions of greenhouse gas (GHG) emissions. These policies generally increase the cost of delivering energy to consumers. While the world has significant unexploited energy reserves, they are generally carbon intensive and, therefore, more expensive to produce under carbon regulations. Hence, efforts to expand energy supply and make it more affordable may be on a collision course with policies to curb greenhouse gas emissions.

The electricity choices facing Arizona are a good example of this challenge. The demand for electric power in Arizona has been growing with an expanding population and higher levels of economic activity. There are several electricity generation technologies available with varying degrees of carbon intensity to meet this growing demand for electric power. Conventional coal-fired power generation, for example is low cost but carbon intensive while solar power is carbon free but much more expensive. Are consumers willing to pay for more expensive carbon free technologies when gasoline is over $4 per gallon? The answer depends in part upon the relative cost of these technologies. To shed light upon this question, this study forecasts future consumption of electric power in Arizona and the cost of meeting that demand under different choices for new electricity generation capacity and under policies that significantly reduce GHG emissions.

To establish the boundaries of this future, this study develops an econometric model that identifies and measures the sensitivity of energy consumption to economic growth and energy prices. The model represents end-use energy demand in all sectors of the Arizona economy, including households, manufacturing, services, agriculture, and electric power generation. The demand for primary fuels — oil, natural gas, and coal — used in power generation, is derived from the demand for end-use electricity consumption. End-use electricity prices are determined from average generation costs and transmission and distribution charges. The overall model provides a tool for policy makers to assess the impacts of economic growth, energy prices, and electricity capacity choices on energy demand, prices, and environmental emissions.

Developing a model of energy demand that provides stable forecasts and sensible policy analysis requires a combination of economic analysis, data measurement, and quantitative modeling. Empirical models consistent with economic theory often ensure that policy and market shocks yield sensible results, such as consumption falling with increasing prices. Practical knowledge of the structure of energy consumption and the forces affecting its development is also critical to successful model development. The judgments made on the basis of these guidelines are discussed in this report.

The next section provides an overview of electricity consumption and generation trends in the Arizona economy. The presentation of the model then appears, including the mathematical specification of the energy demand models for the residential, commercial, and industrial sectors and the formulation of the model for electric power generation and fuel use. Econometric methods are employed to estimate how electricity users respond to prices and economic activity. The forecasting model is then put to work given assumptions on future prices for the primary fuels and projections of population, inflation, and economic growth to generate baseline projections for electricity demand, generation costs, electricity rates, and carbon emissions. The study then examines the demand, cost, and emission impacts of different technological paths for supplying electricity. The impacts of adopting policies to substantially reduce GHG emissions from current levels are then presented. The study concludes with a summary of the major findings and recommendations for future policy considerations.

Arizona Electricity

The consumption of electricity in Arizona has been growing significantly faster than the national average growth rate over the past couple of decades. During the 1980s, electricity use in Arizona grew by 4.7 percent per annum with growth rates above 5 and 6 percent in the residential and commercial sectors respectively (see Table 1). The commercial sector includes all establishments other than manufacturing, mining, and agriculture, which are included in the industrial aggregate. The growth rate for total US electricity use was 3 percent over the same period. During the 1990s, the growth rates for power use in Arizona declined but overall consumption growth was still quite strong at 3.5 percent, substantially above the 2.3 national average growth rate. This pattern continues so far this decade with total electricity use growing 3.4 percent annum between 2000 and 2007 while the national average annual growth rate is 1.3 percent.

Table 1: Growth Rates for Electricity Use by Sector by Decade, 1970-2006

Period	Residential	Commercial	Industrial	Total
1970-79	8.5%	6.8%	5.9%	7.1%
1980-89	5.1%	6.1%	2.2%	4.7%
1990-99	3.9%	3.6%	2.5%	3.5%
2000-06	5.2%	3.3%	-0.2%	3.4%

Most of the growth in Arizona electricity use is occurring in the residential and commercial sectors as Table 1 illustrates. In 1970, the residential, commercial, and industrial sectors each comprised about one-third of total end use electricity consumption (see Figure 1). By 2006, residential and commercial consumption constituted more than 83 percent of total electricity use. Residential use now is the single largest consuming sector requiring over 32 million megawatt hours (Mwh) of electric power during 2006. Commercial sector use is second with 28 million Mwh of consumption. Industrial use is a distant third with 12 million Mwh used in 2006. Together these sectors required more than 72 million Mwh of electicity in 2006.

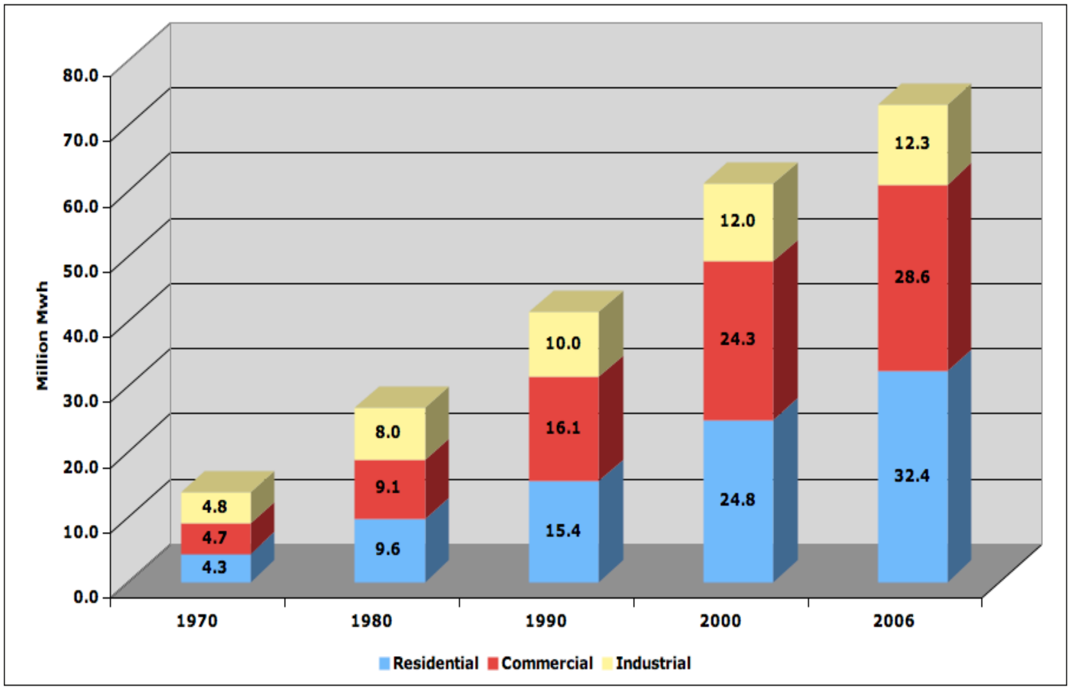


Figure 1: Electricity Consumption by Sector

One of the main drivers of growth in residential electricity consumption has been an expanding population. Population in Arizona rose from 2.7 million in 1980 to 6.2 million in 2006. Since 1990, the growth in electricity use exceeded population growth rates. For example, electricity use during the 1990s grew 3.5% while population increased 3.3%. Similarly, from 2000 to 2006 electricity consumption rose 3.4% while population grew 2.9%.

Table 2: Population Levels and Growth Rates in Arizona, 1970-2006

	Population at Start	Growth Rate
1970-79	1.8	4.3%
1980-89	2.7	3.1%
1990-99	3.7	3.3%
2000-06	5.2	2.9%
2006	6.2	

One reason for electricity use rising faster than population growth has been lower real rates for electric power. Trends in real electricity rates by sector are displayed in Figure 2. During the 1970s, real rates for residential users rose 3% while rates for commercial and industrial users increased 5% per annum. These trends began to reverse during the 1980s and accelerated during the 1990s as real rates feel between 2.6% and 2.9% for residential and industrial users respectively. Electricity rate declines decelerated during the 2000s and recently rates appear to be heading upward.

Figure 2: Real Electricity Rates by Sector

Much of the variation in end-use electricity rates is associated with changes in the average costs of generating electric power. Under traditional public utility pricing, rates are established on the basis of the average cost of production. These costs depend upon the unit operating costs of the various plants in the system and the mix of generation assets. Unit operating costs depend upon capacity utilization and the amount of energy in fuels required to generate a unit of electricity.

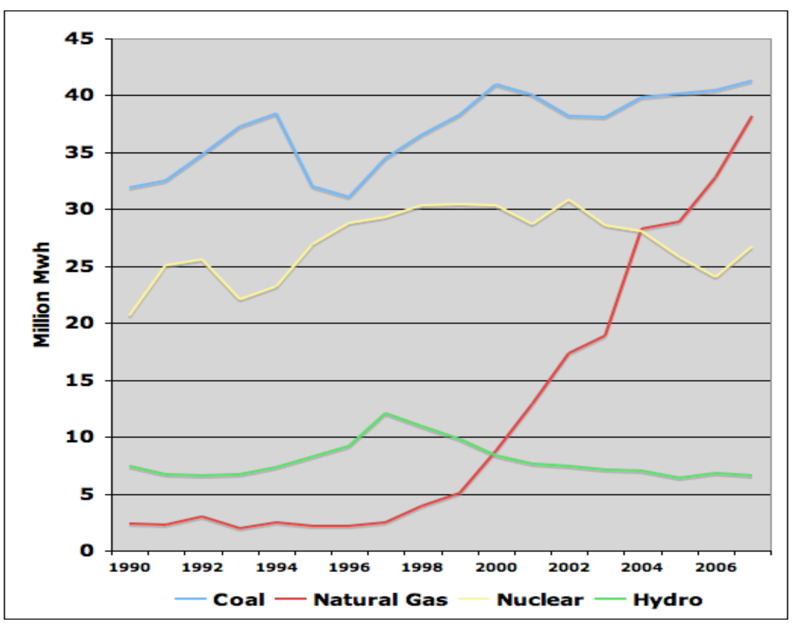


Figure 3: Electricity Generation by Capacity Type

Coal-fired generation is currently the single largest source of electric power in Arizona, producing over 40 million Mwh in recent years (see Figure 3). Arizona is a significant coal producer with more than 8 million tons of output from the Black Mesa region in the northeastern part of the state. Significant amounts of coal are exported to Nevada for power generation there.

Prior to 2004, nuclear power was the second largest source, generating roughly 30 million Mwh during the late 1990s after which maintenance problems contributed to production declining to the 25 million Mwh level. This energy is generated at the Palo Verde station, which is the largest nuclear power plant in the nation. Another source of electric power in the state is hydroelectric from the two large dams on the Colorado River, Glen Canyon and Hoover.

The coal, nuclear, and hydroelectric generation capacity that collectively generates about 75 million Mwh constitutes a large volume of low-cost generation. As the following chart illustrates (see Figure 4), having a low-cost buffer in the generation portfolio shields consumers from the vagaries of fuel prices. As the grid becomes more specialized or more dependent upon high cost sources of power, this vulnerability of electricity rates to shocks in primary fuel prices increases.

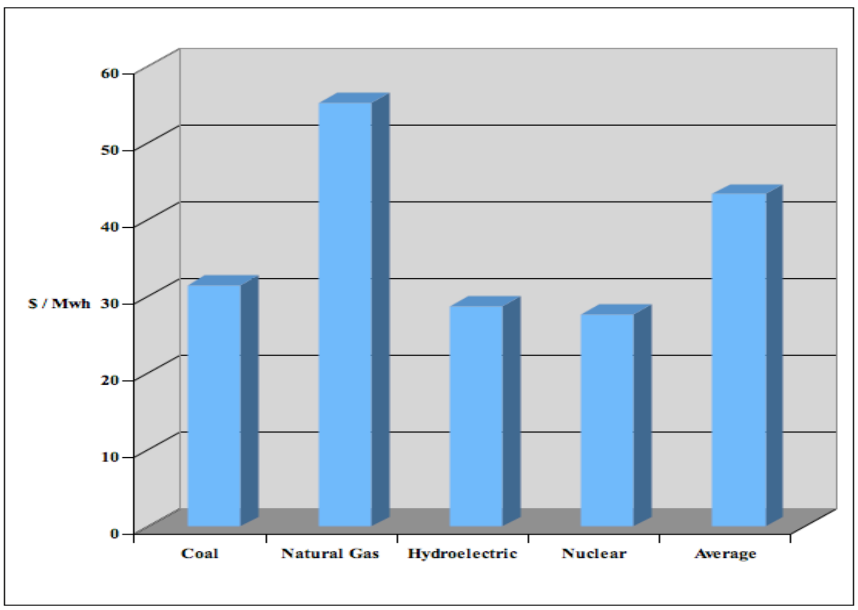


Figure 4: Generation Costs in Arizona by Capacity Type, 2007

Currently, the second largest source of electric power is natural gas, supplying about 36 million Mwh during 2006. In fact, natural gas-fired electric power generation in Arizona is up over 7-fold since the late 1990s. This rapid growth in the use of natural gas to generate electricity reflects a national trend. Even though the price for natural gas is on average 3-5 times higher than coal prices on a thermal equivalency basis, natural gas plants are less capital intensive and do not involve the extensive and elaborate pollution control systems as many coal-fired plants require. As a result, nearly all new electric generation capacity in Arizona since the late 1990s has been natural gas-fired capacity (see Figure 5).

These four sources of electricity generate more than 100 million Mwh, which is 25 million Mwh greater than Arizona end-use. This surplus is exported to other states, in particular Southern California. Much of this power is sold under long-term off-take agreements so exports are unlikely to respond quickly to policies that impact power generation and use in Arizona.

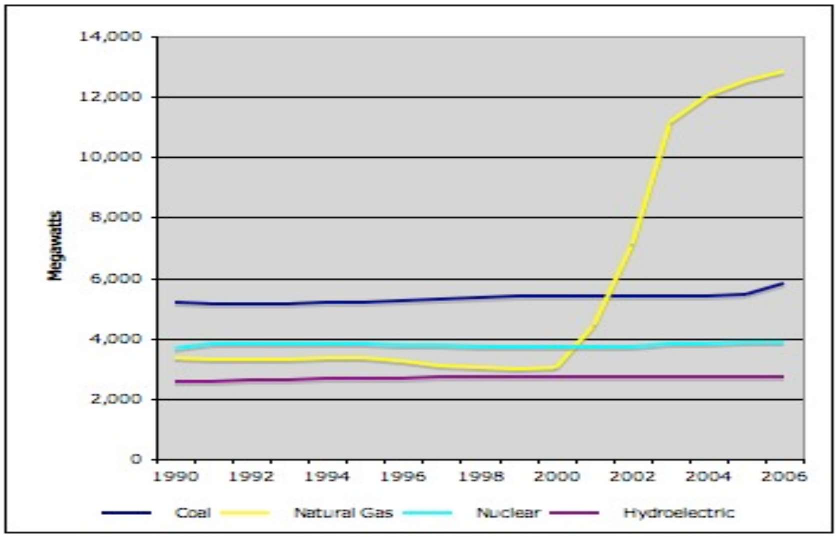


Figure 5: Electricity Generation Capacity in Arizona

In addition to the mix of capacity, another important cost determinant is the rate of capacity utilization. While natural gas capacity and generation have soared in Arizona over the past decade, utilization rates of gas capacity have been rather flat in recent years (see Figure 6).

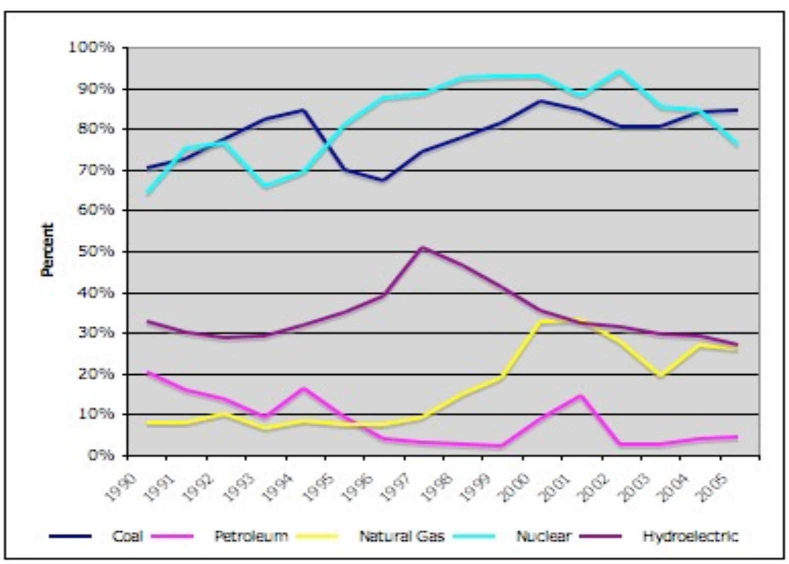


Figure 6: Electric Power Capacity Utilization Rates

In contrast, capacity utilization rates for coal-fired power plants have steadily improved over the past decade and now exceed nuclear capacity utilization. These variations in capacity utilization reflect the role various types of capacity have in meeting electricity loan balancing requirements. Natural gas and oil capacity, for example, are often used to meet peak loads while coal, nuclear, and hydroelectric capacity services base load capacity that varies little hour-to-hour

Another potentially significant energy resource in Arizona is solar power. Arizona has the greatest solar potential in the United States with the highest solar radiation per square meter. Currently Abengoa Solar is building a 280-megawatt solar plant 70 miles outside of Phoenix. This plant does not use photovoltaic cells that collect photons from the sun for conversion to electric current but employs the suns rays using parabolic mirrors to generate heat for conventional steam turbine power generation. This plant employs an innovative storage system that allows the plant to store heat and then later use it for generating power during nighttime or peak demand periods. This strategy increases the plant's utilization rate, thereby, lowering unit costs. The economic feasibility of thermal solar plants critically depends upon this storage system delivering these higher capacity utilization rates.

The Forecasting Model

The forecasting framework is built upon two modeling perspectives. First, the end-use demand for fuels in the residential, commercial, and industrial sectors are modeled from an economic perspective in which energy demand is a function of relative prices, population, and the level of economic activity. On the supply-side for electricity, however, an engineering-economic perspective is adopted in which capacity, utilization rates, and heat rates are specified exogenously with the exception of electricity generation from natural gas, which is determined as the difference between demand and other generation sources. Hence, natural gas is modeled as the swing fuel, which is consistent with the recent past in Arizona. In most economic evaluations of alternative energy systems, such as solar, wind, and biomass, natural gas prices are used as the basis for comparison, in other words, the opportunity cost of electricity from these new technologies is the avoided cost of electricity produced from natural gas.

The forecasting model determines electricity supply, demand, and prices given exogenous assumptions for primary fuel prices, economic growth, inflation, and capacity expansion plans. A schematic of the line of causality between these assumptions and the endogenous variables is presented below in Figure 7. End-use electricity demands and net electricity exports determine electric power generation requirements, which then drive the consumption of fuels in power generation. Generation capacity, operating rates, and heat rates of operating units determine the composition of fuel consumption by electric utilities and the average cost of electricity generation. Retail electricity prices are calculated by adding transmission and distribution charges to average generation costs.

As Figure 7 illustrates, carbon emissions are tracked for each sector of the economy. The carbon tracking provides a nearly complete accounting of carbon dioxide emissions in the Arizona economy. Carbon emissions, therefore, are endogenous and depend upon energy prices and economic activity driving energy demand and the choice of electricity generation capacity.

The feedback of final electricity demand on the demand for fuels and end-use electricity prices allows an integrated evaluation of electricity demand and fuel choice in power generation.

There are five main components of the model. The first three include systems of energy demand equations for the residential, commercial, and industrial sectors. The fourth involves the demand for transportation fuels, including gasoline and diesel fuel. The fifth and final component involves the electricity generation sector. The following sub-sections describe the formulation of the models within each of these components.

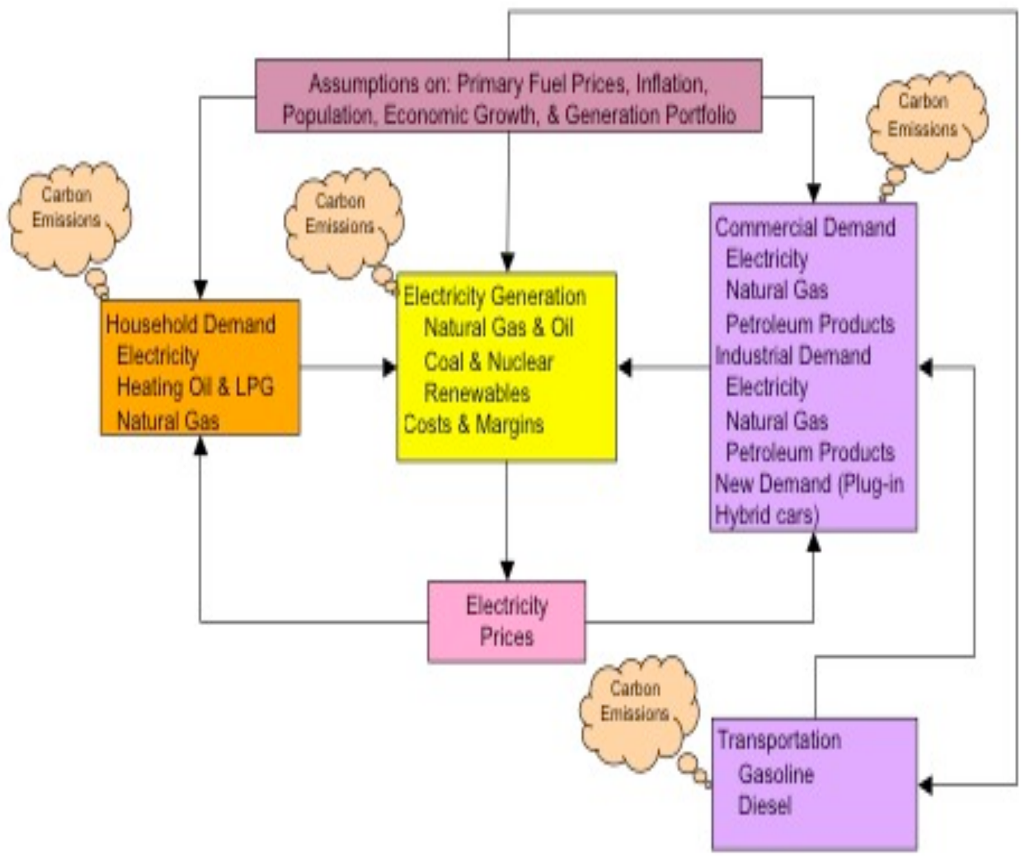


Figure 7: Model Overview

End-Use Stationary Energy Demand The energy demand equations in the residential, commercial, and industrial sectors are specified as expenditure systems. This approach incorporates two key features of demand systems consistent with consumer utility maximization or producer cost minimization. The first feature is that only relative prices matter in determining the mix of fuels. The importance of relative price changes follows from the homogeneity condition of demand equations, which implies that if all prices increase by the same proportionate amount then total energy expenditures also increase by the same percentage. The other important property involves symmetry. If the demand for fuel oil increases when relative propane prices increase, then propane and oil are substitutes. Similarly, the demand for propane should increase with relatively higher oil prices. This suggests, for example, that when a demand equation for oil reflects substitution with coal, then the coal equation should predict that coal is also a substitute with oil. An energy demand forecasting system with inter-fuel substitution should have these symmetric price effects.

Economists have developed a variety of methodologies for ensuring consistency between demand equations. One group of methods use flexible functional forms to approximate systems of demand equations derived from neoclassical cost or expenditure functions, such as the translog (TL) and generalized Leontief (GL). Considine (1989) shows that the nonlinear price elasticities associated with these forms often result in counter-intuitive results, such as positive own price elasticities. In addition, incorporating dynamic quantity adjustments is impossible using the TL and highly restrictive for the GL.

The linear logit (LL) model of cost shares developed by Considine and Mount (1984) provides an attractive alternative to conventional demand systems. Many researchers associate logit functions with discrete choice models. Logistic functions ensure that probabilities are non-negative and sum to one. These properties also must hold for cost shares. Considine and Mount (1984) derive the symmetry and homogeneity conditions for the linear logit cost share system. They also show that this specification is particularly well suited for modeling dynamic adjustments. A dynamic specification is essential because it is unlikely that energy consumers would respond fully to shocks within one period. Furthermore, Chavas and Segerson (1986) argue that the logit approach does not place any restrictions on autoregressive processes of structural error terms.

There are several applications of linear logit demand models that examine various aspects of energy demand. Considine (1989) uses the model to examine how fuels should be grouped in substitution models and estimates the impacts of environmental regulations and policies on natural gas allocation. The report by Jones (1995) applies the model to U.S. industrial energy demand and finds that it out performs other models in terms of fitting observed data and in providing sensible demand elasticities. Considine (2000b) estimates linear logit demand models to estimate the sensitivity of energy demand to fluctuations in climate conditions. Considine and Rose (2000) use the model to forecast world natural gas, petroleum, and coal consumption out to the year 2020 under alternative oil price scenarios and carbon tax policies.

This study adopts the following nested two–stage approach for the residential, commercial, and industrial sectors. The first stage determines the level of total energy consumption. The second stage model disaggregates aggregate energy consumption by fuel type. The mathematical specification of this two–tiered model structure is described in the Appendix to this report.

Demand for Gasoline and Diesel These two fuels are included because a plug-in hybrid scenario is considered in the model simulations. For this simulation, a baseline projection of gasoline and diesel fuel is required. If the sales of plug-in hybrids and a depreciation of car are specified then a working stock of these vehicles can be computed. Assuming some set utilization rate in terms of miles traveled per year along with assumptions on fuel economy, the required electricity and displaced gasoline or diesel fuel can be computed. So the model allows new uses and fuels.

Unlike the residential, commercial, and industrial sectors, very limited or no interfuel substitution yet occurs in the transportation sector, which for this study includes gasoline and diesel fuel. The models in this sector take the same form as equation (3). In this case, the demand shifter includes real personal disposable income and price is the real price including taxes.

Electricity Production The model computes electricity generation by fuel type on the basis of available capacity and average operating rates. For instance, generation from capacity *i* in year *t* in megawatt hours is defined as follows:

$$G_{it} = H_i \times C_{it}\,, \qquad (1)$$

where H_{it} is the number of hours capacity is operated and C_{it} is rated capacity in megawatts. Fuel demand is simply the generation multiplied by the average heat rate:

$$F_{it} = HR_i \times G_{it}\,, \qquad (2)$$

where HR_{it} is the heat rate in tons of oil equivalent per megawatt hour. The forecasts produced below assume fixed operating hours and heat rates, computed using historical values.

A previous version of this study used a linear logit cost share system to model the derived demand for fuels in electric power production. The problem with this approach is that capacity constraints are not explicitly considered. Moreover, a demand system estimated during a period with coal, fuel oil, and gas-oil would most likely not be applicable to one with a substantial share of natural gas. Although relative prices for these fuels do indeed provide estimates of how heat and utilization rates vary with relative fuel prices, the relative environmental costs and benefits of these fuels are not considered. Environmental concerns are likely to be a major factor in the conversion of oil fired electric power generation capacity to natural gas. Operating hours for coal capacity during 1999-2001 are quite likely at their maximum, given necessary outages for maintenance. If oil capacity is replaced by natural gas and coal capacity hours and capacity are fixed, then relative prices cannot affect gas generation because it is swing capacity, or the last units operated to meet system power load requirements. Introducing relative price effects, therefore, is a moot issue given these assumptions.

The computation of forecasted power generation and fuel use by electric utilities can be seen as a sequence of steps. First, total electricity production is determined by adding predicted electricity demand and power line losses. Generation from natural gas fired capacity is determined by the difference between power demand and the sum of generation from other generation sources. Marginal generation costs for electricity are computed by taking an output-weighted average of generation costs by capacity, which is simply the product of fuel prices and heat rates. Margins for transmission and distribution costs are estimated over the historical period by subtracting marginal generation costs from end-use electricity prices. Adding these margins to average generation costs projects end-use electricity prices. This formulation allows end-use electricity prices to vary with oil, coal, and natural gas prices, which then feedback on electricity demand and production.

Model Oveview A listing of the endogenous variables in the energy demand forecasting model appears in Table 3. Coal, petroleum, nuclear, hydroelectric, solar, other renewable sources, or natural gas fired fossil fuel power generation can meet demand requirements. The cost share systems include an aggregate energy quantity equation. The quantities are derived by multiplying energy expenditures, which equal the divisia price index multiplied by the corresponding quantity index, by the respective cost share and then dividing by the appropriate price. The model is programmed using the econometric software package, Time Series Processor (TSP) 4.5 from Stanford University.

Table 3: Model endogenous variables and identities

Endogenous Variables	***Type***	***Endogenous Variables***	***Type***
Residential Sector		*Commercial Sector*	
Divisia energy price	I	Divisia energy price	I
Aggregate energy quantity	B	Aggregate energy quantity	B
Cost shares & quantities		Cost shares & quantities	
Natural Gas	B	Natural Gas	B
Liquid Propane Gas, etc.	B	Petroleum Products	B
Electricity	B	Electricity	B
Electricity Generation		*Industrial*	
Generation & Fuel Use		Divisia energy price	I
Natural Gas	I	Aggregate energy quantity	B
Nuclear	B	Cost shares & quantities	
Coal	B	Boiler & Process Fuels	B
Hydroelectric	B	Natural Gas	B
Other Renewables	B	Coal	B
Electric power generation	I	Petroleum products	B
Electricity consumption	I	Electricity	B
Average Generation Costs	I	Other petroleum products	B
Retail Electricity prices	B	Electricity	B
		Transportation	
		Gasoline in road travel	B
		Diesel in road travel	B
I = Identity, B= Behavioral			

Econometric Findings

The parameters of the four energy demand models – residential, commercial, industrial, and transportation – are estimated with econometric techniques. The presence of total energy quantity on the right-hand side of the cost share equations requires an instrumental variable estimation method to avoid simultaneous equation bias in the estimated coefficients. For this study, the Generalized Method of Moments (GMM) estimator is used, which corrects the standard errors for hetereoscedasticity and autoregressive moving average error components in the stochastic error terms. The strategy for selecting the instrumental variables is the same for each sector, using prices lagged one-period, quantities lagged two periods, a time trend, and lagged values of the exogenous variables in the total energy quantity models, such as the number of customers or real industrial production.

The GMM estimates for the residential energy model, which contains three estimating equations, appears below in Table 4. The parameters reported in the top half of Table 4 corresponds with those that appear equation (7) above. The parameter estimates for the two log cost share ratio equations have no clear, direct interpretation. To achieve an understanding of their implications, the elasticities of demand are reported below in Table 5. Nevertheless, five of the eight parameters of the residential cost share system are significantly different from zero with probability values indicating virtually no chance that the estimated coefficients are zero.

Table 4: Parameter Estimates and Summary Fit Statistics for Residential Sector

Parameters*	Coefficient	t-statistic	P-value
β_{12}	1.388	0.959	[.338]
β_{23}	-1.040	-7.934	[.000]
β_{13}	-0.922	-21.305	[.000]
ϕ	0.846	33.080	[.000]
γ_1	-0.063	-1.349	[.177]
α_1	0.641	0.954	[.340]
γ_2	-0.329	-2.967	[.003]
α_2	4.271	2.617	[.009]
Dependent variable: $\ln(Q_e)$			
Constant	0.219	1.871	[.061]
$\ln(P_e$ / PGDP)	-0.223	-10.473	[.000]
$\ln(Q_{renew})$	-0.043	-3.916	[.000]
ln(Customers)	0.639	7.805	[.000]
$\ln(Q_{e,t-1})$	0.386	5.232	[.000]

Dependent Variable	Correlation Coefficient	Durbin Watson
Natural Gas	0.996	2.38
Liquid Propane Gas	0.901	2.04
Electricity	0.999	1.58
Total Energy Consumption	0.996	2.21

NOTE: 1 = Natural Gas, 2 = Liquid Propane Gas, 3 = Electricity
* See Appendix

Reported in the center of the Table 4 are the parameter estimates from equation (3) above. The double log partial adjustment formulation of the total energy demand equation implies that the coefficients on price and the other exogenous variables in the equation are short-run elasticities. For example, the short-run own price elasticity of total residential energy demand, which is the sum of electricity, natural gas, and petroleum products, is -0.22. Also included in this equation is the amount of renewable energy used in the residential sector. This energy comes mainly from wood and biomass. Given that prices for residential renewables are not observed, the inclusion of the quantity of renewable energy used is intended to indirectly capture the substitution of renewable fuels for conventional ones (see Table 4). Our estimated elasticity of -0.043 in the short-run indicates that renewable fuels do displace conventional energy but the effect is small, probably due to thermal inefficiencies. This specification allows the modeling of distributed power generation in which the amount of energy provided by solar cells and other similar devices act to reduce the required amount of purchased energy.

Rather than income, the number of electricity customers is included in the model because the initial focus of this study involved the determination of the electricity requirements for an additional one million households in Arizona. For this reason, having an explicit link to the number of households or customers was deemed worthwhile. There is not an exact one-to-one correspondence with the number of electricity customers and households but the approximation is quite close.

The summary fit statistics reported in Table 4 result from computing the predicted cost shares and using the cost share identity to compute quantities. A static method was used so that past predictions of lagged quantities are not used. Although a dynamic simulation, which involves using lagged endogenous quantities, is used below in the forecasts, a static method of fit assessment is preferred so that errors are not propagated. Using a static-fit method reveals that the residential model provides an excellent fit of the quantities as measured by the R-squared measures of fit in Table 4. Moreover, the Durbin Watson statistics indicate that an auto-correlated pattern in the residuals does not pose a serious problem.

The own, cross-price, and output elasticities for the residential sector appear in Table 5. All own price elasticities are negative as expected. The own price elasticity of demand for electricity is -0.01, which is very price inelastic and consistent with findings in many other parts of the world. This elasticity is highly significant represented by the high t-statistic and low probability value, which is the tail probability that the estimate is zero. The own price elasticities for liquid propane gas and natural gas are relatively larger but still inelastic. The elasticities reported in Table 5 are gross elasticities that assume the level of total household energy demand is held constant. In reality, changing relative fuel prices affects the price of aggregate fuels to households that in turn affects the level of energy consumption.

The objective function value of the GMM estimator is distributed as a Chi-Squared statistic, providing a test of the over-identifying restrictions for the model. For the residential model the probability value for the over-identifying restrictions is 0.848, suggesting that the restrictions cannot be rejected. Hence, the overall model appears to be supported by the data sample.

The curvature conditions, which follow from consumer utility maximization, are checked at the mean of the data by computing the Eigen values of the first derivatives of the estimated demand functions. For consistency with economic theory, the implicit expenditure function should be concave, which occurs when the Eigen values are less than zero. The residential estimates imply that these conditions are satisfied. Hence, the residential energy demand functions are properly signed and on this basis provide intuitively plausible results in policy simulations.

Table 5: Own, Cross-Price, and Customer Elasticities for Residential Sector

		Gross Elasticities		
Quantities	Natural Gas Price	Liquid Propane Gas price	Electricity Price	Customers
Natural gas	-0.14	0.08	0.06	-0.04
t-statistic	-2.8	1.6	1.8	-1.1
probability value	[.005]	[.099]	[.073]	[.268]
Liquid Propane Gas	0.37	-0.34	-0.03	-0.31
t-statistic	1.6	-1.8	-0.3	-2.9
probability value	[.099]	[.065]	[.763]	[.003]
Electricity	0.01	0.00	-0.01	0.02
t-statistic	1.8	-0.3	-1.3	2.2
probability value	[.073]	[.763]	[.180]	[.026]
Quantities		***Net Elasticities***		
Natural gas	-0.18	0.05	0.03	0.61
t-statistic	-3.5	0.9	0.8	7.5
probability value	[.001]	[.361]	[.410]	[.000]
Liquid Propane Gas	0.36	-0.34	-0.04	0.44
t-statistic	1.6	-1.9	-0.4	4.5
probability value	[.106]	[.059]	[.710]	[.000]
Electricity	-0.17	-0.18	-0.19	0.65
t-statistic	-9.9	-10.4	-9.3	7.8
probability value	[.000]	[.000]	[.000]	[.000]
Quantities		***Net Long-Run Elasticities***		
Natural gas	-0.98	0.46	0.35	0.75
t-statistic	-2.7	1.5	1.4	3.3
probability value	[.006]	[.133]	[.155]	[.001]
Liquid Propane Gas	2.39	-2.20	-0.22	-1.05
t-statistic	1.7	-2.1	-0.3	-1.4
probability value	[.095]	[.040]	[.754]	[.154]
Electricity	-0.22	-0.30	-0.36	1.18
t-statistic	-4.6	-8.2	-5.9	19.6
probability value	[.000]	[.000]	[.000]	[.000]

The second group of elasticities in Table 5, labeled net elasticities, account for these effects on total energy consumption. Notice that the own price elasticities of demand are larger in absolute terms. This is logical, given the negative own price elasticity of demand for aggregate household energy demand. The customer elasticities are also substantially larger than the gross income elasticities, which measure how substitution possibilities vary with the level of income. The short-run net customer elasticities for natural gas, liquid propane gas, and electricity are 0.61, 0.44, and 0.65, respectively.

The long run elasticities are also reported in the last panel of Table 5. These elasticities are a function of the net elasticities divided by one minus the respective adjustment parameters. As expected, the long-run own price and income elasticities are substantially larger than the gross and net elasticities. For example, the long-run own price elasticity of demand for electricity is -0.36 with customer elasticity of 1.18. In summary, the elasticities of demand for the household sector model seem quite reasonable and the fit of the model is excellent.

The overall findings from the econometric estimation of the commercial energy demand model are quite similar to the residential result. As Table 6 indicates, six out of the eight parameters in the commercial cost share system are significant. In addition, all of the coefficients are significantly different from zero in the aggregate commercial energy demand equation. The short-run aggregate price elasticity of demand for energy in the commercial sector is -0.052 and this increases to -02.26 in the long-run. The overall fit of the commercial sector is also quite good, although the Durbin-Watson statistics indicate some degree of serial correlation in the error terms.

Like the residential sector, the number of electricity customers is used to shift the overall level of aggregate commercial energy use because various measures of commercial sector economic activity did not yield acceptable results. Again the resulting elasticity of aggregate energy demand to customers is reasonable with a short-run elasticity of 0.19, increasing to about one in the long-run. The elasticities for the commercial sector are reported in Table 7. The short-run own price elasticity for electricity in the commercial sector is very small and significantly different from zero. The long-run price elasticity of demand for electricity in this sector is -0.356 and the long-run customer elasticity is slightly over one.

Like the residential sector, the test of the over-identifying restrictions for the commercial model cannot be rejected. In addition, the concavity conditions are correctly signed. Overall, the econometric results yield plausible estimates for the elasticities and a model that would likely perform well in policy simulations.

The econometric results for the industrial model are displayed in Tables 8 and 9. Unlike the first two models, the number of industrial electricity customers did not yield acceptable results. As a result, a measure of industrial production was devised by adding value added from manufacturing and an estimate of value added in mining, based upon the gross value of mineral production in Arizona. The estimation results imply a short-run output elasticity of 0.078 for electricity in the industrial sector that increases to 0.268 in the long-run.

Table 6: Parameter Estimates and Summary Fit Statistics for Commercial Sector

Cost Share System Parameters*	Coefficient	t-statistic	P-value
β_{12}	2.361	1.959	[.050]
β_{23}	-1.022	-7.399	[.000]
β_{13}	-0.869	-21.472	[.000]
ϕ	0.882	16.580	[.000]
γ_1	0.052	0.787	[.431]
α_1	-1.002	-1.182	[.237]
γ_2	-0.500	-3.169	[.002]
α_2	6.602	3.063	[.002]
Dependent variable: $\ln(Q_e)$			
Constant	0.473	4.092	[.000]
$\ln(P_e$ / PGDP)	-0.052	-2.332	[.020]
ln(Customers)	0.194	2.364	[.018]
$\ln(Q_{e,t-1})$	0.805	11.505	[.000]

Dependent Variable	Correlation Coefficient	Durbin Watson
Natural Gas	0.993	1.67
Petroleum Products	0.985	1.74
Electricity	0.999	1.58
Total Energy Consumption	0.999	1.05

NOTE: 1 = Natural Gas, 2 = Petroleum Products, 3 = Electricity
* See Appendix

Several different specifications were tested, each involving different grouping of fuels. After unsatisfactory results, i.e. positive own-price elasticities, a careful examination of the data revealed large, coincidental swings in natural gas and coal consumption during the 1970s. This observation led to the hypothesis that the natural gas and coal are weakly separable from electricity and petroleum products. As a result, a two tiered model was estimated, the first tier modeling the competition between natural gas and coal and the second involving the demand for the natural gas and coal aggregate and how it substitutes with petroleum products and electricity. The coal and natural gas substitution model results appear in Table 10 and yield plausible estimates of the own and cross price elasticities of demand for these fuels with the own price elastity of demand for coal at -0.432 and for natural gas at -0.122 in the long-run.

Table 7: Own, Cross-Price, and Customer Elasticities for Commercial Sector

	Natural Gas Price	Liquid Propane Gas price	Electricity Price	Customers
		Gross Elasticities		
Quantities				
Natural gas	-0.205	0.094	0.111	0.060
t-statistic	-4.3	2.8	3.2	1.0
probability value	[.000]	[.005]	[.001]	[.303]
Liquid Propane Gas	0.404	-0.385	-0.019	-0.492
t-statistic	2.8	-3.1	-0.2	-3.2
probability value	[.005]	[.002]	[.871]	[.001]
Electricity	0.016	-0.001	-0.015	0.008
t-statistic	3.2	-0.2	-2.9	0.8
probability value	[.001]	[.871]	[.004]	[.411]
Quantities		***Net Elasticities***		
Natural gas	-0.212	0.088	0.105	0.205
t-statistic	-4.5	2.6	2.9	2.3
probability value	[.000]	[.009]	[.003]	[.020]
Liquid Propane Gas	0.403	-0.386	-0.021	0.098
t-statistic	2.8	-3.1	-0.2	2.3
probability value	[.005]	[.002]	[.861]	[.024]
Electricity	-0.029	-0.045	-0.059	0.195
t-statistic	-1.3	-2.4	-3.2	2.4
probability value	[.184]	[.015]	[.001]	[.018]
Quantities		***Net Long-Run Elasticities***		
Natural gas	-1.780	0.767	0.916	1.501
t-statistic	-2.3	1.9	1.9	2.3
probability value	[.024]	[.057]	[.062]	[.020]
Liquid Propane Gas	3.430	-3.282	-0.170	-3.172
t-statistic	2.0	-2.0	-0.2	-1.8
probability value	[.048]	[.048]	[.864]	[.074]
Electricity	-0.094	-0.233	-0.356	1.061
t-statistic	-0.6	-1.9	-2.6	9.7
probability value	[.539]	[.055]	[.010]	[.000]

Table 8: Parameter Estimates and Summary Fit Statistics for Industrial Sector

Cost Share System Parameters*	Coefficient	t-statistic	P-value
β_{12}	-0.555	-0.960	[.337]
β_{23}	-0.982	-11.566	[.000]
β_{13}	-0.901	-11.482	[.000]
ϕ	0.876	26.754	[.000]
γ_1	0.033	0.295	[.768]
α_1	-0.623	-0.402	[.688]
γ_2	-0.145	-0.793	[.428]
α_2	1.910	0.747	[.455]
Dependent variable: $\ln(Q_e)$			
Constant	3.896	3.783	[.000]
$\ln(P_e$ / PGDP)	-0.057	-2.822	[.005]
ln(Industrial Production)	0.078	2.100	[.036]
$\ln(Q_{e,t-1})$	0.666	6.944	[.000]

Dependent Variable	Correlation Coefficient	Durbin Watson
Natural Gas	0.835	2.94
Petroleum Products	0.621	1.86
Electricity	0.964	2.12
Total Energy Consumption	0.763	2.14

NOTE: 1 = natural gas, 2 = petroleum products, 3 = electricity
* See Appendix

The tests of the over-identifying restrictions are not rejected. The estimates satisfy the curvature conditions implying that the demand equations are consistent with producer cost minimization. Like the residential and commercial sectors, the short-run demand for electricity is extremely price inelastic with a short-run own price elasticity of -0.021. This elasticity increases in the long-run to -0.28.

The final block of estimated econometric equations include the demands for gasoline and diesel fuel used in transportation. These equations are estimated to provide a baseline to estimate the incremental fuel savings from adopting plug-in hybrid vehicles. The results of this estimation appears in Table 11. The short and long-run price and income elasticities of demand are well within the range reported in the literature. Like electricity, the short-run demand for these fuels is very inelastic indicating that consumer expenditures rise sharply as prices increase.

Table 9: Own, Cross-Price, and Output Elasticities for Industrial Sector

	Gross Elasticities			
Quantities	Natural Gas & Coal Price	Petroleum Product Prices	Electricity Price	Industrial Production
Natural Gas & Coal	-0.137	0.072	0.064	0.050
t-statistic	-1.8	0.8	1.3	0.5
probability value	[.076]	[.442]	[.207]	[.641]
Petroleum Products	0.083	-0.095	0.011	-0.127
t-statistic	0.8	-0.6	0.2	-0.8
probability value	[.442]	[.531]	[.836]	[.437]
Electricity	0.019	0.003	-0.021	0.017
t-statistic	1.3	0.2	-1.8	0.7
probability value	[.207]	[.836]	[.076]	[.514]
Quantities	***Net Elasticities***			
Natural Gas & Coal	-0.147	0.062	0.054	0.082
t-statistic	-1.9	0.6	1.1	2.3
probability value	[.054]	[.517]	[.282]	[.022]
Petroleum Products	0.074	-0.104	0.002	0.068
t-statistic	0.7	-0.7	0.0	1.7
probability value	[.498]	[.488]	[.969]	[.083]
Electricity	-0.018	-0.034	-0.058	0.080
t-statistic	-1.2	-1.6	-3.2	2.1
probability value	[.249]	[.117]	[.001]	[.036]
Quantities	***Net Long-Run Elasticities***			
Natural Gas & Coal	-1.136	0.553	0.488	0.330
t-statistic	-1.7	0.7	1.3	1.7
probability value	[.081]	[.485]	[.198]	[.089]
Petroleum Products	0.645	-0.793	0.065	-0.007
t-statistic	0.7	-0.6	0.1	0.0
probability value	[.478]	[.522]	[.885]	[.984]
Electricity	0.039	-0.088	-0.284	0.268
t-statistic	0.4	-0.7	-2.4	3.4
probability value	[.700]	[.515]	[.018]	[.001]

Table 10: Estimated Parameters and Price Elasticities for Industrial Fuel Sub-Aggregate

	Coefficient	t-statistic	P-value
Dependent variable: $\ln(Q_{gasoline})$			
α_1	0.209	1.1	[.293]
β_{12}	0.881	3.6	[.000]
ϕ	0.786	5.5	[.000]
	Correlation	Durbin	
Dependent Variable	Coefficient	Watson	
Gasoline	0.718	2.10	
	Short-Run		
	Price Changes		
	Natural Gas	*Coal*	
	-0.026	0.026	
Natural Gas	-0.48	0.48	
	[.627]	[.627]	
	0.092	-0.092	
Coal	0.48	-0.48	
	[.627]	[.627]	
	Long-Run		
	-0.122	0.122	
Natural Gas	-0.6	0.6	
	[.546]	[.546]	
	0.432	-0.432	
Coal	0.6	-0.6	
	[.546]	[.546]	

Table 11: Parameter Estimates & Elasticities of Demand for Gasoline and Diesel Fuel

	Coefficient	t-statistic	P-value
Dependent variable: $\ln(Q_{gasoline})$			
Constant	1.031	3.6	[.000]
$\ln(P_{gasoline}$ / PGDP)	-0.077	-3.0	[.003]
ln(Real Personal Income)	0.169	2.8	[.006]
$\ln(Q_{gasoline,t-1})$	0.685	6.3	[.000]
Dependent variable: $\ln(Q_{diesel})$			
Constant	-2.120	-2.6	[.009]
$\ln(P_{diesel}$ / PGDP)	-0.077	-1.1	[.263]
ln(Real Personal Income)	0.385	3.5	[.000]
$\ln(Q_{diesel,t-1})$	0.575	4.6	[.000]

Dependent Variable	Correlation Coefficient	Durbin Watson
Gasoline	0.835	2.94
Diesel	0.621	1.86

	Short-Run		
	Price Changes		
	Gasoline	*Diesel*	*Income*
	-0.077		0.169
Gasoline	-3.0		2.8
	[.003]		[.006]
		-0.08	0.39
Diesel		-1.1	3.5
		[.263]	[.000]
	Long-Run		
	-0.244		0.538
Gasoline	-1.9		18.0
	[.525]		[.000]
		-0.18	0.91
Diesel		-1.0	9.6
		[.400]	[.000]

Baseline Forecast

To perform forecasts with the econometric model, assumptions are required for economic growth, inflation, and primary fuel prices. In addition, to develop alternative generation scenarios, costs for new capacity additions are required. The full econometric model, including the behavioral equations discussed above, the cost, generation, and retail rate equations for the electric power sector, the carbon accounting relations, involves the simultaneous solution of 127 equations. Simulations are performed using TSP 4.5 Gauss-Newton algorithm. All simulations are performed from 2008 to 2030.

This study assumes real gross domestic product and the corresponding price deflator each grow at 2.5 percent per annum. Population growth rates decline from current levels of around 3 percent to less than 1.5% by 2030 so that population is 7 million in 2010, 8.7 million in 2020, and 10 million in 2030. Based upon the historical trend of a falling number of people per household, these population projections imply that Arizona will add one million households by 2018.

There is a very high degree of uncertainty surrounding future trajectories of primary fuel prices. The Energy Information Administration (EIA) latest set of projections calls for declining real oil prices. The International Energy Agency, however, recently anticipates additional problems with world oil production capacity keeping pace with demand growth. This study assumes that recent tightness in primary fuel prices will continue into the future. Specifically, from 2008 averages of $110 per barrel for oil, $10 per thousand cubic feet for natural gas, and $32 per ton for coal, real growth rates for oil, natural gas, and coal, are assumed to be 4%, 3%, and 1% respectively. The natural gas price is a key variable in this study because it determines the marginal value of electricity generation costs given that the model assumes by construction that natural gas is the swing fuel.

Given these assumptions and assuming exports of electricity from Arizona remain at current levels, total electric power consumption (residential, commercial, and industrial) in the state rises from approximately 75 million Mwh in 2008 to 95 million Mwh by 2018 after the addition of 1 million households (see Figure 8). Hence, adding one million households will require 20 million megawatts of electricity. Demand eventually rises to over 116 million Mwh by 2030. Hence, by the end of the forecast period the state will require an additional 42 million Mwh of electricity. Average annual growth in consumption is 2 percent, considerably below recent growth rates. By the end of the forecast period, electricity demand is growing about 1.5% just about equal to population growth.

Another factor dragging down future demand growth is rising real rates for electric power. Real generation costs rise from over $50 / Mwh to more than $100 / Mwh in 2030. This simply results from rising real prices for natural gas assumed in the baseline forecast scenario and from a rising share of natural gas in the electricity capacity portfolio. These higher costs translate to higher retail prices displayed in Figure 9 and rising real monthly household expenditures on energy from current levels of more than $300 per month to almost $450 per month by 2030 (see Figure 10).

Total carbon dioxide emissions increase from current levels of roughly 100 million tons to over 133 million tons by 2030. Note that these emissions result from the combustion of natural gas, coal, and petroleum products in the residential, commercial, industrial, and transportation sectors of the Arizona economy. The average annual increase in carbon emissions is 0.9 percent, less than the growth in energy consumption because all new generation capacity is natural gas, which is less carbon intensive than coal and petroleum products.

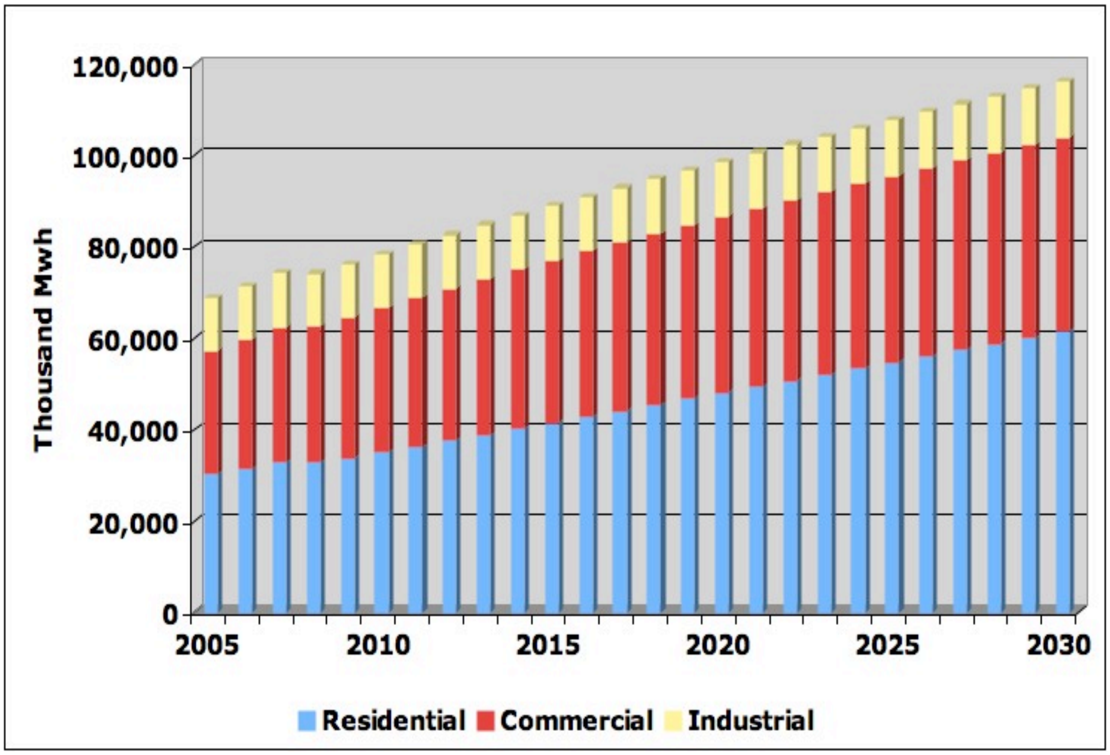


Figure 8: Forecast of Electricity Consumption in Arizona

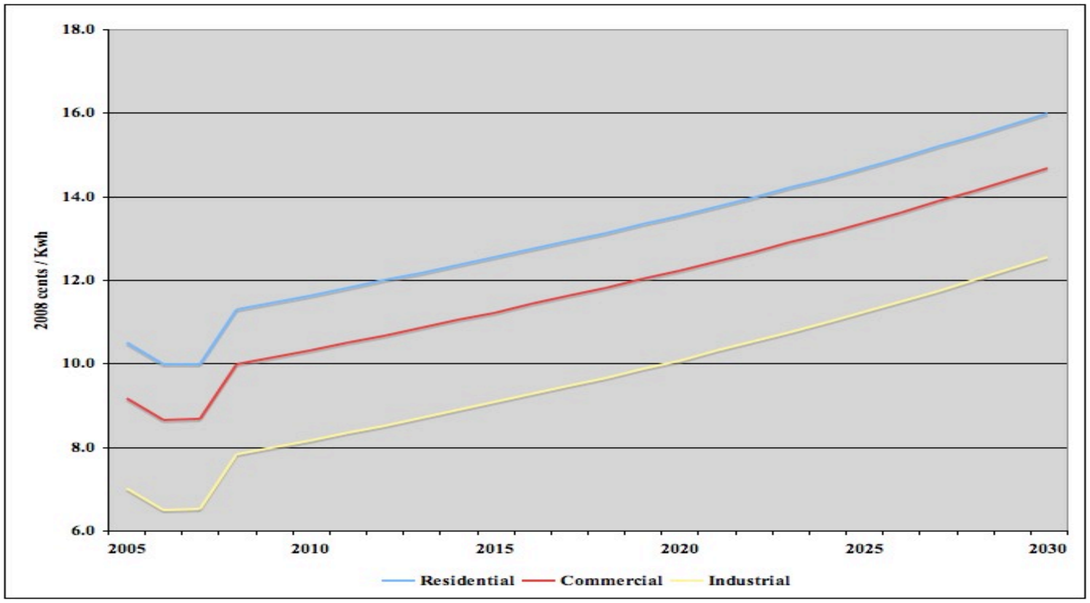


Figure 9: Real Electricity Rates by Sector

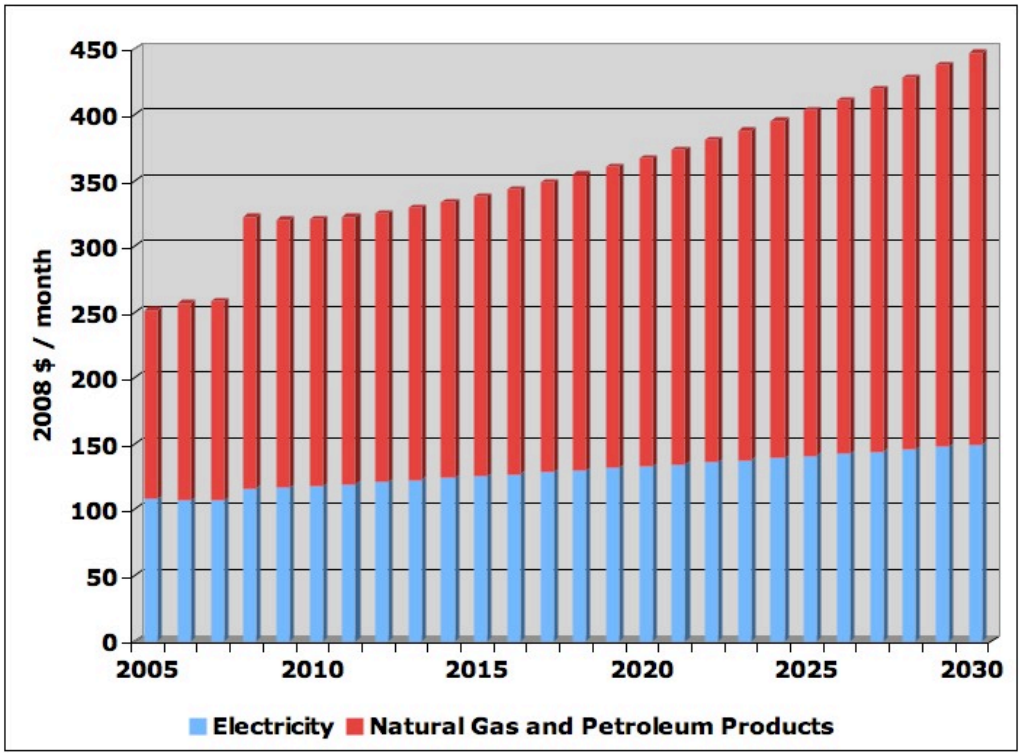


Figure 10: Real Monthly Household Energy Expenditures

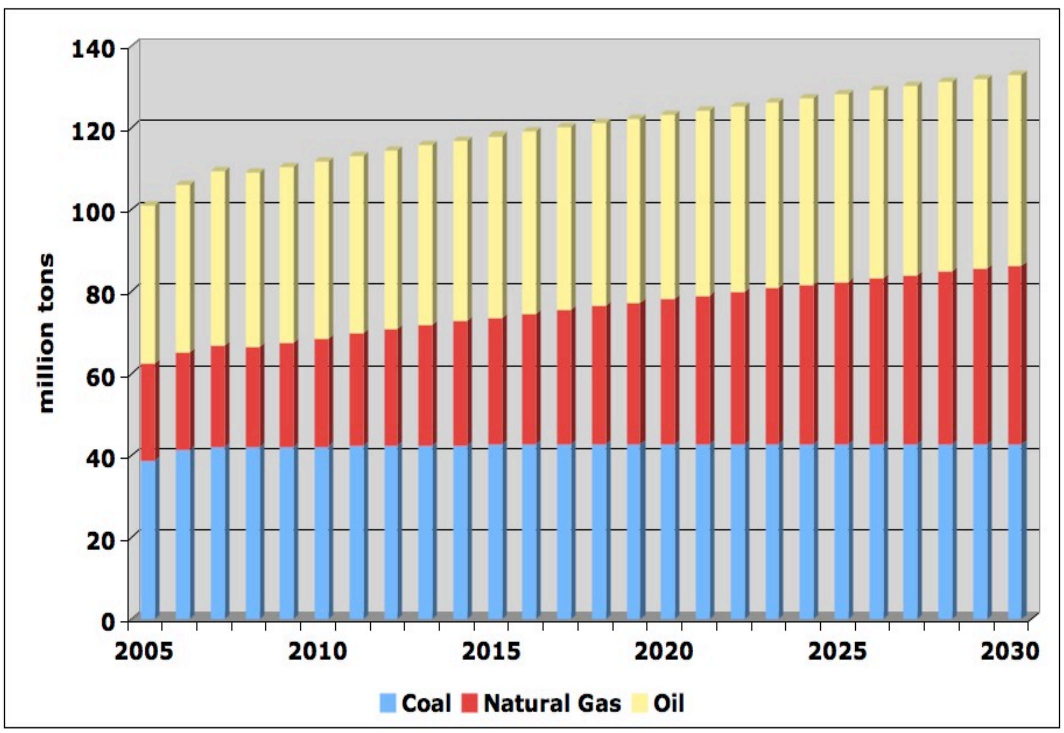


Figure 11: Carbon Dioxide Emissions

Alternative Generation Capacity Scenarios

The baseline scenario presumes that all new electric generating capacity is natural gas. There is nothing sacrosanct about this assumption. Indeed, a rising reliance on any one fuel runs counter to the principles of modern portfolio theory that preaches diversification. To determine the cost and environmental trade-offs of various generation portfolio choices, consider replacing three-fourths of all new natural gas capacity installed from now to the year 2030 with the following four alternative capacity scenarios:

- Scrubbed conventional coal,
- Integrated Gasification Combined Cycle (IGCC) using coal with carbon capture and storage,
- Advanced nuclear energy,
- Solar thermal power with plug-in hybrid vehicles, and
- A portfolio of capacity with an equal share of the last three capacity choices.

Electricity demand, generation costs, and retail rates under each of these scenarios are simulated using the econometric model based upon estimates of the costs of installing and operating these generation technologies, which is known as *levelized* costs.

Levelized costs are defined as the variable costs of operation plus a capital cost recovery component, which is amortized capital costs of installation. This study assumes a 12% discount rate in the computation of the capital recovery factor. Operating and capital costs are estimated for a base year and then projected into the future based upon the Energy Information Administration's forecasts of future generation costs. Given recent price increases in basic materials, such as steel and concrete, capital costs have escalated dramatically in recent years.

The levelized costs of each of the new technologies are plotted below in Figure 12. First, notice the sharp spike in costs in 2008, reflecting higher material prices. After 2008, costs for advanced nuclear, coal based IGCC with carbon capture and storage, and conventional scrubbed coal are essentially flat in real terms because technological progress in the operation and installation acts to keep costs under control. Conventional natural gas generation technology also experiences these effects but higher natural gas prices offset these cost reductions.

Solar thermal costs are substantially higher than the other generation technologies. Costs of solar thermal are highly sensitive to its operating rate. This study uses observed data from the 64MW Nevada Solar One plant that was constructed for $250 million that reported 134,000 Mwh of electricity generation, which implies a 24% capacity utilization rate and a levelized cost of over $250 / Mwh. The solar industry recognizes this challenge to increase operating rates to lower the actual delivery price of energy from these facilities. Clearly there is considerable room for progress. The low operating rates for solar implies that a MW of solar capacity does not displace a MW of conventional fossil fuel capacity. If the solar operating rates could be increased, this would dramatically reduce the cost of solar generated electricity.

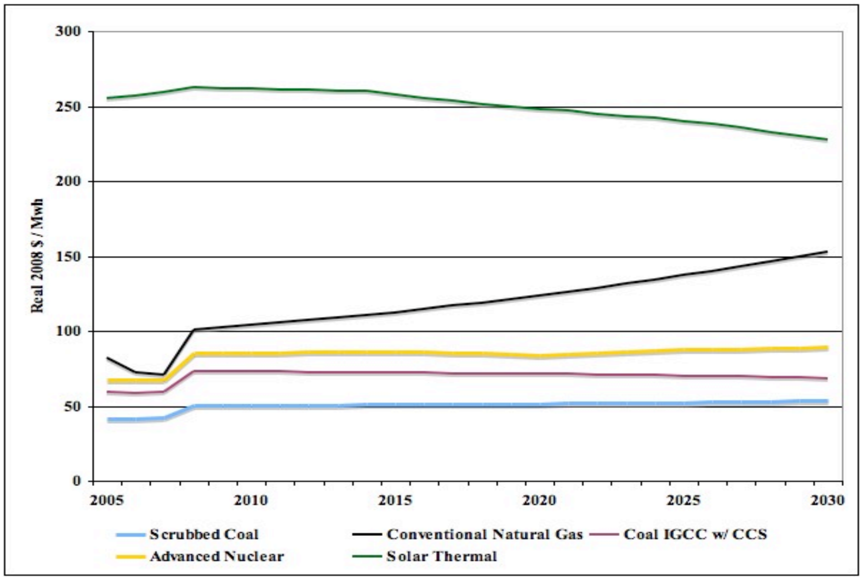
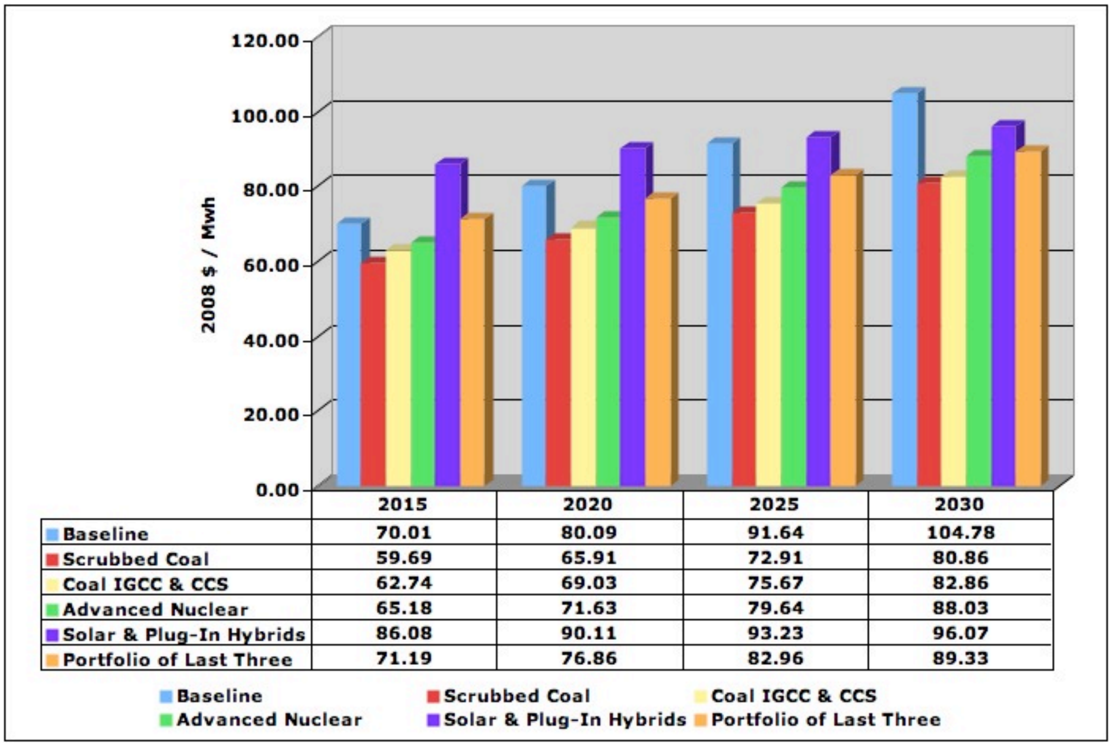


Figure 12: Levelized Costs of New Generation Capacity

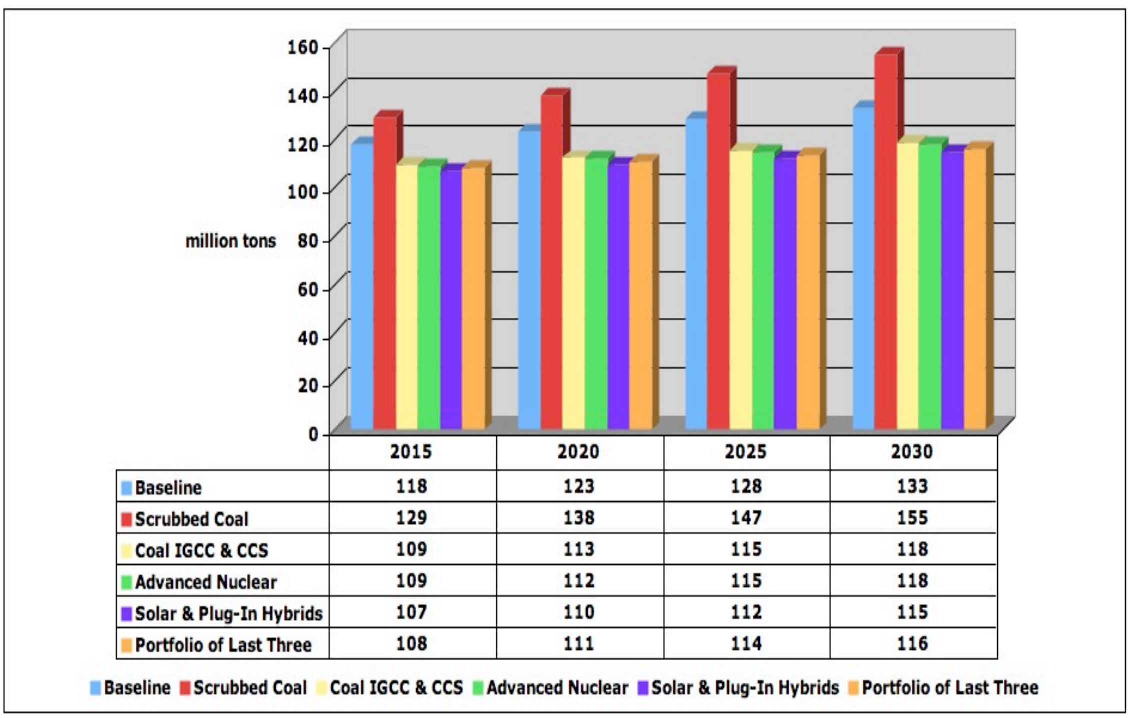
The solar thermal capacity scenario also assumes the adoption of plug-in hybrid vehicles. The use of these vehicles directly reduces carbon dioxide emissions by reducing gasoline consumption in transportation but increases the demand for electricity. If the electricity source is carbon free substantial reductions in carbon emissions are possible. For this scenario, this study assumes initial sales of 6,000 units in 2010. Based upon recent trends in hybrid car sales, sales of plug-in hybrids are projected based upon a growth rate of 32% in 2010 that declines linearly to 6% by 2023 and remains at that level. Assuming a depreciation rate of 3%, the stock of plug-in hybrids reaches over 675,000 units by 2030. Currently, there are about 5 million cars on the road in Arizona. This study assumes that plug-in hybrids save 326.8 gallons of gasoline per year based upon typical miles traveled per year and use 1,840 Kwh per vehicle per year.

The simulations results for real generation costs are displayed in Figure 13. In the baseline, real generation costs essentially double due to an increasing reliance on natural gas fired capacity and higher real natural gas prices. The scrubbed coal capacity scenario, which involves replacing ¾ of new natural gas capacity with conventional scrubbed coal capacity, yields substantially lower rates but increases carbon emissions by 22 million tons per year in 2030 (see Figure 14). Turning this around, by foregoing the construction of coal-fired generation and if real natural gas prices rise in the future, the baseline scenario essentially involves cutting carbon emissions at a relatively high price. For example, consumers pay more than $700 million more in rates under the baseline than the scrubbed coal scenario. What do they get for this? Our estimates suggest a carbon emission reduction of 11 million tons. So the implicit cost per ton of emissions avoided is $62 and this cost rises to over $80 per ton in 2030. The economic literature suggests a long-term equilibrium price for carbon of $40 per ton. This comparison suggests that continuing the status quo of essentially using natural gas to reduce emissions could prove quite costly in the long-run.



	2015	2020	2025	2030
Baseline	70.01	80.09	91.64	104.78
Scrubbed Coal	59.69	65.91	72.91	80.86
Coal IGCC & CCS	62.74	69.03	75.67	82.86
Advanced Nuclear	65.18	71.63	79.64	88.03
Solar & Plug-In Hybrids	86.08	90.11	93.23	96.07
Portfolio of Last Three	71.19	76.86	82.96	89.33

Figure 13: Real Generation Costs under Different Capacity Choices



	2015	2020	2025	2030
Baseline	118	123	128	133
Scrubbed Coal	129	138	147	155
Coal IGCC & CCS	109	113	115	118
Advanced Nuclear	109	112	115	118
Solar & Plug-In Hybrids	107	110	112	115
Portfolio of Last Three	108	111	114	116

Figure 14: Carbon Emissions under Different Capacity Choices

The other four capacity choices are more speculative and should be viewed as possible but not probable. There are many reasons. First, while IGCC technology is now ready for deployment and appears capable of capturing carbon emissions efficiently, transporting carbon dioxide and storing it in large volumes is not yet demonstrated. Similarly, advanced nuclear plants appear promising but until one is actually built in the USA the true costs remain uncertain. The specter of construction delays due to public opposition to nuclear power is another real risk. Nevertheless, simulation of the Arizona energy sector with these technologies proves a useful "what-if" exercise to assess the potential environmental gains and their costs.

Among the three alternative technologies coal-based IGCC with carbon capture and storage appears the most cost effective, followed closely by advanced nuclear power. Both of these technologies lower generation costs from the baseline that assumes continued reliance on natural gas for new capacity. The solar and plug-in hybrid scenario significantly reduces carbon emissions from the baseline but also substantially raises generation costs in the short and medium term. Generation costs under the solar hybrid scenario decline during the out-years as the efficiency of solar thermal technology improves. The final capacity scenario involves an equally weighted portfolio of IGCC, nuclear, and solar capacity. Under this path carbon emissions are reduced and, as expected, generation cost fall between the other scenarios.

Under all scenarios, even the solar and plug-in one, carbon dioxide emissions increase from 2008 to 2030 because economic growth creates additional electricity and primary fuel consumption. This suggests that to cut carbon emissions below current levels, the existing generation base must be changed.

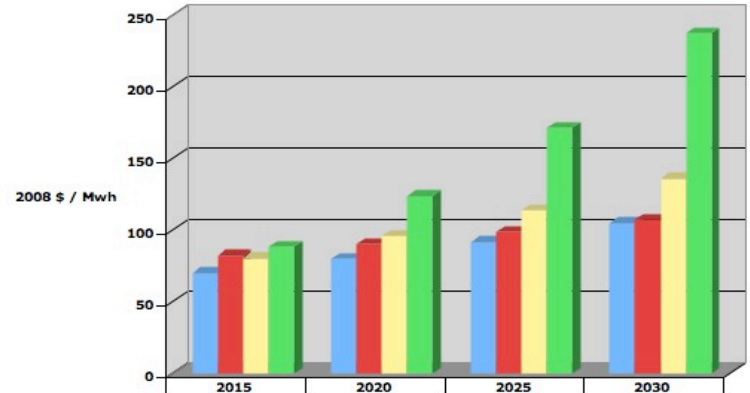
Cutting Carbon Emissions

This section examines the options for achieving a 15% reduction in carbon dioxide emissions from 2005 levels by the year 2020. To attain this goal, this study examines the impacts of phasing out existing coal-fired capacity under the following three scenarios:

- Replacing this capacity with a combination of IGCC, nuclear, and solar capacity,
- Reverting to even more natural gas if these new technologies are not available, and
- Reverting on natural gas under higher natural gas prices.

The last scenario is intended to represent the possibility that other states in the western US also experience delays in constructing IGCC, nuclear, or renewable energy facilities and also revert to using natural gas. If this were to occur, the entire region would substantially increase natural gas consumption. The cost and environmental impacts of these scenarios appear in Figures 15-16.

A similar situation occurred during the electricity crisis in California of 1999-2000. While nefarious trading practices captured many of the headlines and no doubt played a role in the sharp spike in electricity prices during this time, shifts in regional power supplies also played a role. During the winter of 1999-2000, the snow pack in coastal ranges and intermountain west was unusually low. With the lack of spring water run-off to power hydroelectric facilities, electricity producers increase their consumption of natural gas by 30 percent. As a result, natural gas prices doubled. Therefore, the last scenario assumes a gradual doubling of natural gas prices from their baseline levels.



	2015	2020	2025	2030
Baseline	70	80	92	105
New Technology	82	90	98	107
No New technology	80	96	114	136
No New technology & Higher Natural Gas Prices	88	124	171	237

Figure 15: Impact of Phasing Out Coal-Fired Power on Real Electric Power Generation Costs

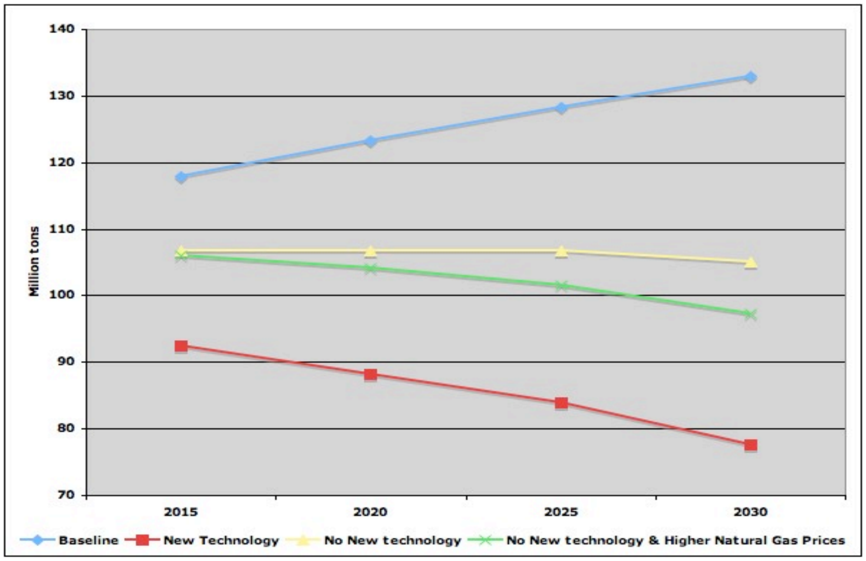


Figure 16: Carbon Emissions from Phase-Out of Coal-Fired Generation

Phasing out existing coal capacity and replacing it with a combination of IGCC, nuclear, and solar capacity raises rates significantly in the short to medium term and somewhat less so in the long-run (see Figure 15). More substantial increases in rates are possible if these new technologies are not adopted and producers revert to even more natural gas powered generation. If this switch to natural gas translates to higher natural gas prices, generation costs and retail electricity rates could more than double.

Conclusions and Recommendations

The future of Arizona is tied to energy. The quality of life here, as well as the rest of the nation, improved dramatically with the widespread availability of abundant energy to power improvements such as air conditioning. Now, however, we are in the midst of a contentious debate over global climate change while demand for energy worldwide continues to expand. That higher global need means people in Flagstaff, Phoenix, and Bisbee will pay more for the energy required to power their homes and their cars.

The imposition of massive reductions in carbon dioxide emissions in response to concerns about climate change will also require consumers to pay more for their energy. Dealing with these issues, including personal energy consumption, is about economic trade-offs. The economic reality is that there are limited resources available to meet unlimited demands. That means a restructuring of priorities is required. Public expenditures for energy or environmental measures means there will ultimately be fewer dollars to pay for other public and private needs, from health care to education. The question is whether the trade-off is worth the cost required.

Arizona and other states are caught in an economic tug-of-war for scarce energy between developing nations and developed nations. Most homes in China have no electricity, and the nation is building one new coal fired plant a week to meet that demand. The Chinese are also subsidizing drivers $50 billion to keep gasoline prices down which, in turn, pushes demand.

This report has attempted to put these realities in perspective for Arizona, but it also has application in every state around the nation. How should we meet the demand for future energy? What are we willing to give up to deal with potential problems caused by its use in the long and short run? Are there other options to deal with that impact?

The decisions about our energy future must be removed from the realm of politics and into the realm of sensible, objective analysis provided by economics, science, and engineering.

Based upon current population and migration trends, Arizona will add another one million households over the next 10 years. These households and related business activity will require an additional 20 million-megawatt hours of electricity. Looking out beyond to the year 2030, these requirements increase to 50 million megawatt hours of electricity.

How will this power be produced? If the past is any guide, the most likely course is to supply this new demand with natural gas fired capacity. As electricity providers in Arizona continue down this path, the electricity system becomes increasing vulnerable to higher natural gas prices. If recent trends for higher natural gas prices continue, electricity rates in Arizona could more than double in real terms over the next two decades. Assuming a 3 percent real rate of growth in natural gas prices and all new capacity is natural gas fired, electricity rates increase:

- by 20% from now to 2015,
- by 33% from now to 2020,
- by 42% from now to 2025, and
- by 60% from now to 2030.

What does this mean for the typical household in Arizona? During 2008, the average household spent over $320 per month on electricity, gasoline, and other fuels. These expenditures rise to $450 per month in today's dollars by 2030 under our baseline forecast.

There are options to cut these costs. Instead of increasing reliance on natural gas, using conventional coal-fired power generation would lower rates 15-25% from the baseline forecast. This coal-based strategy, however, increases carbon emissions. Using natural gas to cut carbon emissions, however, may not be the most cost-effective strategy. Indeed, increasing reliance on the natural as a de facto carbon reduction strategy imposes significant costs on the Arizona economy. This study estimates that the costs of reducing carbon emissions by using larger amounts of more expensive natural gas is between $60 and $80 per ton, considerably above near term projections of carbon prices under a cap and trade regulatory system. More cost-effective means of cutting carbon emissions are available.

Coal-based IGCC with carbon capture and storage and advanced nuclear are two such options. Adopting IGCC and nuclear would likely result in electricity rates somewhere between the baseline reliance on natural gas and conventional coal. The willingness of society to support the construction of these plants, however, remains to be demonstrated. Solar thermal technology has substantially higher costs in the near and medium term compared with conventional coal and gas plants, IGCC, and nuclear designs. For example, replacing new gas-fired capacity with solar thermal plants would raise rates 20% above the baseline-forecast. So instead of rates rising 20% from now to 2015 under the baseline forecast they would rise 40% if Arizona would service new electricity demand with solar capacity.

Even higher electricity rates are likely if governments adopt policies to cut carbon emissions from current levels. To achieve significant reductions in carbon emissions, phasing out *existing* coal-fired generation would be necessary. Replacing this capacity with a portfolio of nuclear, IGCC, and solar would achieve the emission reductions and raise rates from already elevated levels in the baseline forecast. The adoption of these systems, however, is not assured. The backstop technology is once again natural gas and if other states play the same game, natural gas use would increase and prices would soar and electricity rates could rise dramatically. For instance, under this scenario electricity costs in Arizona would rise nearly 80% from now to the year 2020. These simulations reveal an important lesson. Existing coal, hydroelectric, and nuclear capacity are valuable assets, providing a low cost buffer, shielding consumers from rate increases. Policies to dramatically reduce carbon emissions would devalue these assets.

These findings and the uncertainties surrounding generation costs suggest that Arizona may wish to consider maintaining a diversified portfolio of generation assets, continuing to build natural gas fired capacity and adding nuclear, coal or IGCC capacity when the time is right. While solar energy and other renewable energy offer great promise in meeting growing energy demand, a headlong push to build large amounts of solar thermal capacity may be counter-productive by raising rates too high, too fast and diminishing public support to achieve the real promising technological breakthroughs that lie ahead. Abandoning conventional energy sources, such as coal and nuclear, bears some significant risks and if pursued ratepayers may be reminded of that old hit tune, "you don't know what you got…. until it's gone."

Appendix

The demand models involve a non-homothetic, two-stage optimization framework. The first tier assumes an aggregate energy demand relationship:

$$\ln Q_t^d = \eta_r + \kappa_r \ln\left(P_{rt}^d / PGDP_t\right) + \mu_r \ln X_t + \lambda_r \ln Q_{rt-1} + \varepsilon_{rt} \tag{3}$$

where Q_{rt}^d is a divisia quantity index of total energy demand; $\eta_r, \kappa_r, \mu_r, \lambda_r$ are unknown parameters; P_t^d is a divisia index of aggregate fuel prices; X_t is an exogenous demand shifter that differs by sector; and ε_{rt} is a random error term. The divisia price index is a share weighted moving average of logarithmic first differences in fuel prices defined by the following identity:

$$P_t = P_{t-1}\left[1 + 0.5\sum_{j=1}^{n}\left(S_{jt} + S_{jt-1}\right)\left(\ln P_{jt} - \ln P_{jt-1}\right)\right], \tag{4}$$

where n indexes the fuels used in the particular sector. For instance, prices for electricity, liquid propane gas, and kerosene and gas oil comprise the divisia price index for the residential sector. The corresponding divisia quantity index is defined as energy expenditures divided by the divisia price index.

This specification assumes that the fuels in the energy price index are weakly separable from other goods and services. In other words, the marginal rate of substitution between two fuels is independent of the rate at which aggregate energy substitutes with other goods. Substitution possibilities between energy and other goods and services are likely to be very limited within the time span considered in this study.

In the second stage, a system of share equations determines the mix of fuels within each sector's energy aggregate. The unrestricted linear logit model of cost shares is as follows:

$$S_{it} = \frac{P_{it}Q_{it}}{C_t} = \frac{e^{f_{it}}}{\sum_{j=1}^{n} e^{f_{jt}}} \; \forall\, i \text{, where} \tag{5}$$

$$f_{it} = \alpha_i + \sum_{j=1}^{n}\beta_{ij}\ln\left(P_{jt}\right) + \gamma_i Q_t + \phi\ln\left(Q_{it-1}\right) + \varepsilon_{it}, \tag{6}$$

and where Q_{it} is the quantity of fuel *i* in period *t*, P_{it} is the price of fuel *i*, C_t is expenditures on fuels in the aggregate, ε_{it} is a random disturbance term, and where $\alpha_i, \beta_{ij}, \gamma_i, \phi$ are unknown parameters to be estimated. The inclusion of Q_t in equation (6) allows non-homothetic demand functions within a two-stage demand model similar to the formulation developed by Segerson and Mount (1985).

Substituting (4) into (3), taking logarithms, normalizing on the n^{th} cost share, and imposing symmetry and homogeneity following the procedures developed by Considine and Mount (1984), yields the following share system:

$$\ln\left(\frac{S_{it}}{S_{nt}}\right) = (\alpha_i - \alpha_n) - \left[\sum_{k=1}^{i-1} S_k^* \beta_{ki}^* - \sum_{k=i+1}^{n} S_k^* \beta_{ik}^* - S_i^* \beta_{in}^*\right] \ln\left(\frac{P_{it}}{P_{nt}}\right)$$
$$+ \sum_{k=1}^{i-1} (\beta_{ki}^* - \beta_{kn}^*)\ S_k^* \ln\left(\frac{P_{kt}}{P_{nt}}\right) + \sum_{k=i+1}^{n-1} (\beta_{ik}^* - \beta_{kn}^*)\ S_k^* \ln\left(\frac{P_{kt}}{P_{nt}}\right) \tag{7}$$
$$+ (\gamma_i - \gamma_n) \ln Q_t + \phi \ln\left(\frac{Q_{it-1}}{Q_{nt-1}}\right) + (\varepsilon_{it} - \varepsilon_{nt}),$$

for all fuels, i , in the cost share model, where S_k^*'s are the mean cost shares. The residential energy cost share system includes two equations of this basic form. Notice that equations (1) and (5) contain lagged quantities, which allows dynamic adjustments in demand and the computation of short and long–run elasticities. The price and income (output) elasticities are shared weighted functions of the parameters. The adjustment parameter, ϕ , determines the difference between short and long–run elasticities.

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